1997 Annual Report

Granger
ENERGY CORP.

Granger Energy Corp. is a public energy company committed to creating superior shareholder value through finding and producing oil and gas in Canada. The Company's strategy is to exploit business niches, technologies, and information bases which generate superior profitability.

Granger's Class A, Class B, and Class C shares trade on the Alberta Stock Exchange under the symbols GAS.A, GAS.B, and GAS.C.

Contents

Abbreviations

bbl	- barrel
bbls/d	- barrels per day
bopd	- barrels of oil per day
mbbls	- thousands of barrels
BOE	- barrel of oil equivalent (1 bbl = 10 mcf)
BOEPD	- barrel of oil equivalent per day
mcf	- thousands of cubic feet
mmcf	- millions of cubic feet
mcf/d	- thousands of cubic feet per day
ARTC	- Alberta Royalty Tax Credit

Highlights

	November 30 Year End		
Operating	**1997**	1996	% Change
Production			
Oil and NGL's (bbls/d)			
Average	**477**	317	+ 50
Exit	**695**	384	+ 81
Natural gas (mcf/d)			
Average	**533**	872	- 39
Exit	**550**	907	-39
Average price			
Oil and NGL's (bbl)	**$ 23.51**	$ 22.94	+ 02
Natural gas (mcf)	**$ 2.00**	$ 1.65	+ 21
Proven and probable reserves			
Oil and NGL's (mbbls)	**1,541**	1,027	+ 50
Natural gas (mmcf)	**6,625**	4,692	+ 41
Undeveloped land (net acres)	**42,403**	25,450	+ 67
Financial			
Net production revenue	**$ 3,762,000**	$ 2,576,000	+ 46
Cash flow	**$ 2,096,000**	$ 1,216,000	+ 72
Per share - basic	**$ 0.72**	$ 0.46	+ 56
Net earnings	**$ 535,000**	$ 360,000	+ 49
Per share - basic	**$ 0.18**	$ 0.14	+ 29
Capital expenditures, net	**$ 6,655,000**	$ 3,038,000	+ 119
Bank debt	**$ 3,438,000**	$ 500,000	+ 588
Net asset value	**$ 7,632,000**	$ 4,883,000	+ 56
Per basic share	**$ 1.95**	$ 1.83	+ 07
Class A shares outstanding			
Basic	**2,917,880**	2,673,580	+ 09
Weighted average	**2,913,396**	2,655,156	+ 10
Class B shares outstanding	**3,712,000**	3,712,000	–
Class C shares outstanding	**109,634**	109,634	–

Nineteen ninety seven was a year of impressive progress for Granger as new benchmarks were recorded in all key performance categories.

Net Production Revenue rose 46% to $3.76 million, while cash flow increased 72% to $2.1 million. Net earnings increased to $.54 million, a 49% increase over 1996. Granger's earnings to cash flow ratio, a measure of operating efficiency, was a strong 26%. Basic cash flow was $0.72 per share, up 56% from $0.46 per share in 1996. Net earnings were up 29% to $0.18 per share.

Murray Sears, President

Granger's average net oil sales price was $23.51 per barrels, up marginally from $22.94 per barrels in 1996. The average natural gas price improved 21% to $2.00 per mcf.

Significant improvement was made in operating efficiency and profitability margins during the year. Crown royalties and similar revenue deductions declined by 10% to $3.71 per BOE, resulting in a net revenue increase to $19.47 per BOE. Production expenses declined 15% to $4.85 per BOE, assisting in an operating netback improvement of 24% to $14.62 per BOE. Corporate costs declined 2% to $3.38 per BOE, producing an overall corporate cash flow improvement of 32% to $10.85 per BOE.

Depreciation, depletion and amortization costs climbed 20% to $5.82 per BOE and net earnings rose 14% to $2.77 per BOE.

Granger more than doubled its investment activity, spending $6,655,000 on land, drilling and equipment costs compared to $3,038,000 in 1996. Proven reserve additions exceeded production by 4.2 times and the corporate recycle ratio (ie. corporate netback divided by finding and onstream costs) was 1.43 times. Established reserves finding costs of $7.59 per BOE include $970,000 ($1.11 per BOE) for undeveloped land for which no benefit will be realized until drilled in 1998.

Last year in the 1996 Annual Report, several key goals which were important to the Company's success, were identified. The following compares the results actually achieved to those goals:

- Increase the undeveloped land base to support a high rate of sustainable growth.

- *Result: Acquired 16,953 net undeveloped acres, a 67% increase, to 42,403 net undeveloped acres.*

- Expand operations in central Alberta as a new project area for high impact exploration.

- *Result: Acquired 7,027 net acres on 5 projects and drilled one exploration test in the area in 1997.*

- Grow production by 50% and cash flow by 67%.
- ***Result: Average production grew 31% and cash flow grew 72%.***
- Reduce operating costs below $5.00 per BOE.
- ***Result: Operating costs declined to $4.85 per BOE.***
- Increase working interests and operatorship.
- ***Result: Undeveloped land WI grew from 47% in 1996 to 70% in 1997.***
- Maintain net debt at less than 1.5 times forward cash flow.
- ***Result: Year end net debt was 2.1 times 1997 cash flow, reducing to 0.9 times after closing the December 1997 equity issue.***
- Expand the public share float for improved trading liquidity
- ***Result: Class A float increased 135% from 2 MM shares to 4.7 MM shares at January 1, 1998***

The success achieved in 1997 is the result of the commitment and skill of Granger's staff, who focused diligently and creatively on the goal of building a prosperous energy company. I thank them for their efforts and commitment.

I would also like to thank our directors for their valued support during the year.

Murray D. Sears
President

March 4, 1998

Exploration Strategy

Granger's main project areas are located in central Alberta and southern Saskatchewan. These areas have the reserve and production growth opportunities available which best fit the Company's exploration strategy, summarized as follows:

- Explore in areas where the geologic concepts are well understood by management.
- Generate an inventory of high impact projects in-house, using leading-edge technologies (e.g. 3-D seismic, horizontal drilling) where applicable.
- Acquire land positions in low activity areas having year-round access and multi-zone potential.
- Promote third party participation in higher risk plays while maintaining project control.

Saskatchewan

Southeast Saskatchewan Project Area

Granger continued its successful horizontal drilling program in 1997. At Queensdale, four (1.1 net) new horizontals were drilled on the property. One (.19 net) successful well was drilled at Handsworth and two (1.0 net) successful wells were drilled at Ingoldsby. Granger also received a carried working interest (.2 net) in another successful horizontal well drilled at Ingoldsby. Seven of the eight wells had initial production rates in excess of 200 BOPD. Two vertical exploration wells were drilled and abandoned at Heward (1 .0 well net) and Nottingham (.4 wells net). One more horizontal well is planned for Queensdale and Granger will continue to explore in this focus area during 1998.

Tompkins

In 1997, the large acreage block (100.0%) at Tompkins was evaluated seismically. Granger now has four defined locations on these lands. At least one well will be drilled in 1998 on this block.

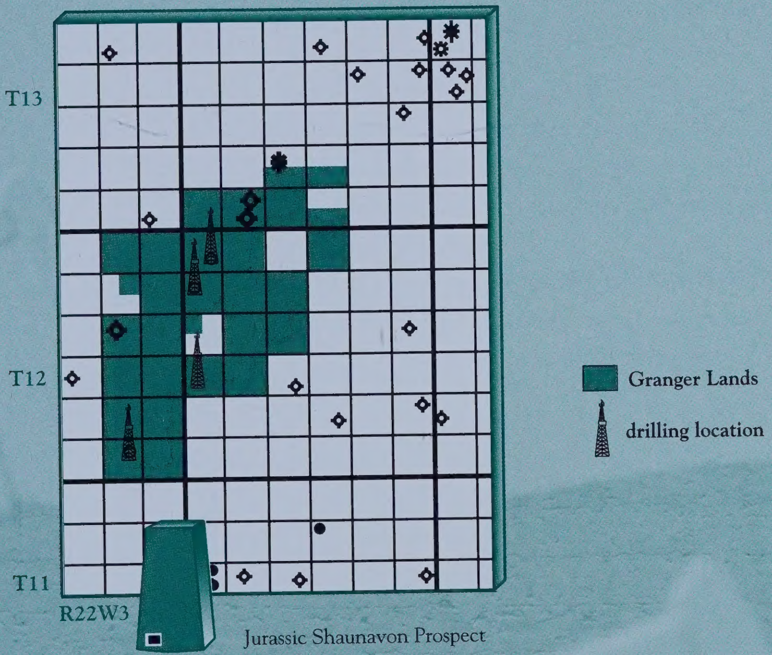
Alberta

Majestic (Atlee-Buffalo)

At Majestic in southern Alberta, Granger participated in nine (1.8 net) new horizontal wells, further developing the Glauconitic pool first drilled in 1996. Granger also participated in two (.4 net) vertical water disposal wells. The 1998 program will consist of ten (2.0 net) new horizontal wells as well as an exploratory Nisku test (.6 net) as a follow-up to a strong oil show encountered in one of the water-disposal wells. A possible Glauconite pool extension will be seismically-evaluated in early 1998 on Granger 40% working interest lands.

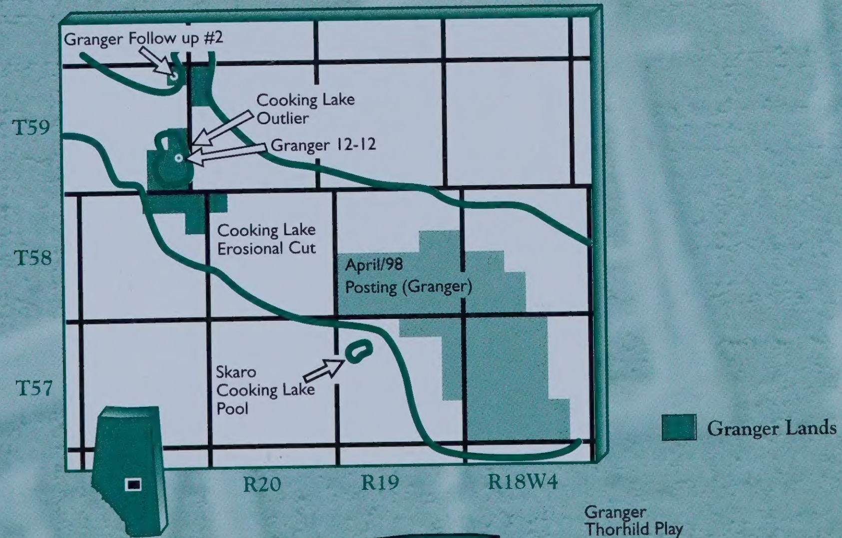
Granger also owns a 70% interest in 23,000 acres prospective for shallow gas exploration and operates a 10 mile gas gathering and compression system in this area. A continued positive outlook for natural gas prices may make this area attractive for exploration later in the year.

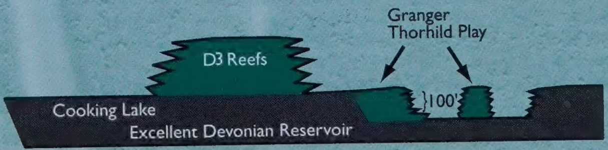
Tompkins



Jurassic Shaunavon Prospect

Thorhild





Devonian Cooking Lake Prospect

Central Alberta

Granger's development focus in 1997 resulted in only one of our high-impact exploration plays in this area being tested during the year. A Nisku gas well (.33 wells net) was drilled on lands at Meanook. Prospect generation efforts throughout the year have given Granger a substantial inventory of plays to be pursued in the upcoming year. Areas include Thorhild, Golden Spike and Thorsby. Pool targets exceed 500,000 BOE's in size.

Production and Reserves

Total production averaged 530 BOEPD, comprised of 477 bopd and 533 mcf/d of natural gas, a 31% increase over the previous year. This increase was achieved primarily from drilling successes at Queensdale, Ingoldsby and Majestic, where combined average production from these areas increased from 90 bopd in 1996 to 324 bopd in 1997.

Granger's reserve life index for oil and gas production is 8.5 years based on Proven reserves and 11.4 years based on Proven plus Probable reserves.

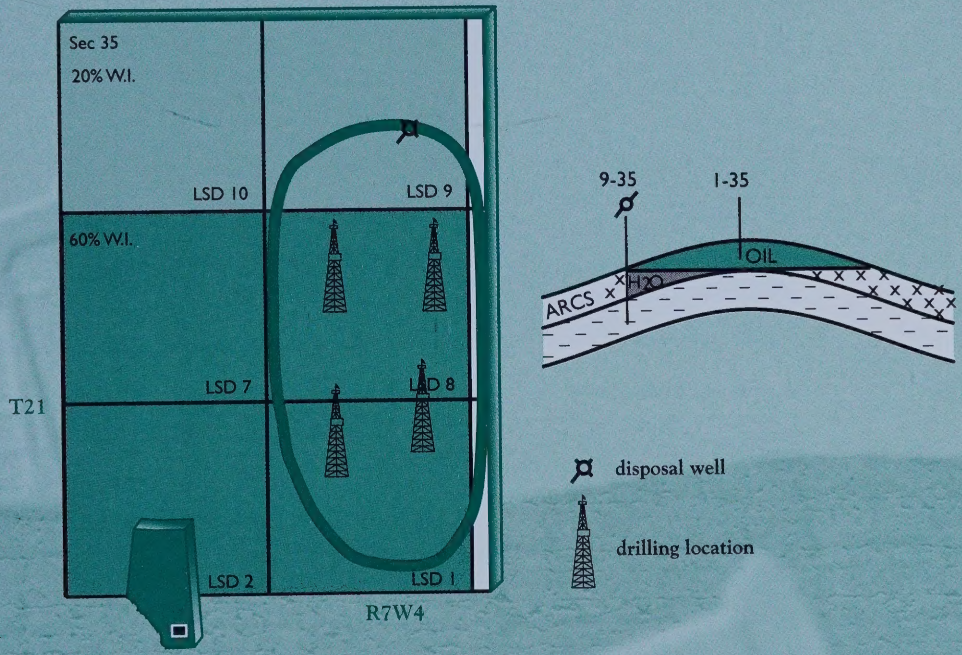
Granger participated in drilling 22 (6.43 net) wells in 1997, resulting in 17 (4.30 net) oil wells, 2 (0.40 net) service wells and 3 (1.73 net) dry holes for a 73% net success rate.

Major Properties

The following table is representative of the daily production and proved reserves of Granger's major producing properties at November 30, 1997.

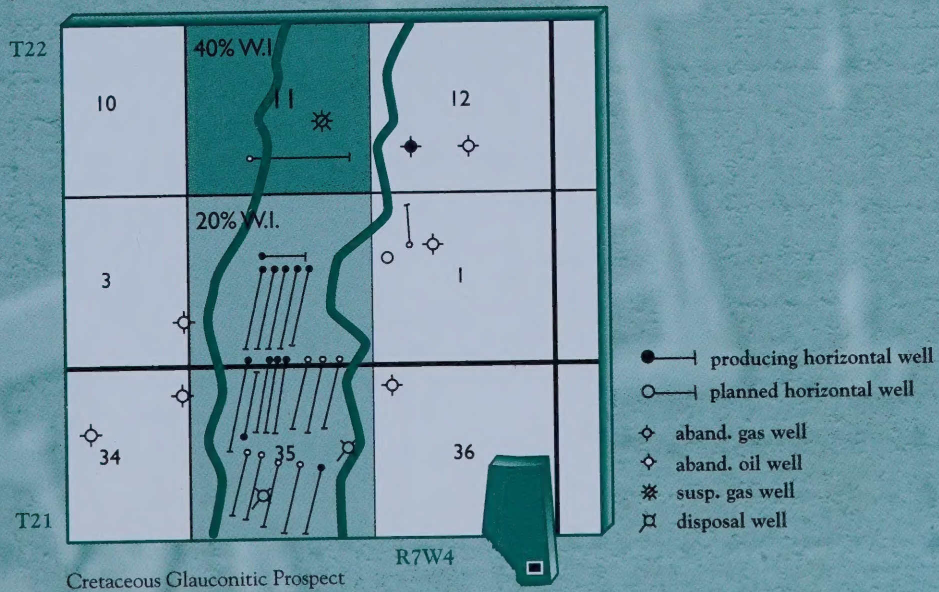
	Production		Proved Reserves	
	Gas (mcf/d)	Oil (bbls/d)	Gas (mmcf)	Oil (mbbls)
Alberta				
Atlee-Buffalo/Majestic	177	62	742	303
Connorsville	169	–	485	–
	346	62	1,227	303
Saskatchewan				
Queensdale	–	145	–	204
Ingoldsby	–	117	–	217
Handsworth	–	81	–	141
	–	343	–	562
Other properties	187	72	4,139	254
Total	533	477	5,366	1,119

Majestic



Devonian Arcs Prospect

Majestic



Cretaceous Glauconitic Prospect

Reserves Reconciliation

	Oil & NGL's (mbbls)			Gas (mmcf)		
	Proved	Probable	Total	Proved	Probable	Total
November 30, 1996	752	275	1,027	3,373	1,319	4,692
Revisions	(118)	22	(96)	711	(188)	523
Additions*	660	125	785	1,474	128	1,602
Production	(175)	–	(175)	(192)	–	(192)
November 30, 1997	1,119	422	1,541	5,366	1,259	6,625
% Change	49	53	50	59	(5)	41

* Includes acquisitions & dispositions

Reserves Volumes

November 30, 1997	Gross Reserves	
	Oil (mbbls)	Gas (mmcf)
Proved Producing	1,011	831
Proved Non-producing & Undeveloped	108	4,535
Total Proved	1,119	5,366
Probable Additional	422	1,259
Total Proved & Probable	1,541	6,625

Reserves Value

		Discounted at	
	Undiscounted	10%	15%
		($000's)	
Proven Producing	$ 16,544	$ 9,884	$ 8,501
Proven Non-producing & Undeveloped	4,764	2,568	1,971
Total Proved	$ 21,308	$ 12,452	$ 10,472
Probable Additional*	4,899	1,520	1,111
ARTC*	971	742	669
Total Proved & Probable	$ 27,178	$ 14,714	$ 12,252

*The dollar value assigned to probable reserves is risked at 50%.

Pricing Assumptions

	WTI at Cushing Oklahoma ($US/bbl)	Light Oil at Edmonton	Alberta Gas Price
1997	20.00	26.02	1.70
1998	20.50	26.67	1.85
1999	21.00	27.32	2.06
2000	22.00	28.65	2.16
2001	23.00	29.98	2.29
2002	24.00	31.32	2.48
2003	25.00	32.65	2.68

Granger's reserves have been evaluated annually since inception by the independent petroleum evaluation engineers Paddock Lindstrom and Associates.

In converting the price of West Texas Intermediate (WTI) oil from United States to Canadian currency, an exchange rate of U.S. $0.73 per Cdn. $1.00 was used. The Alberta gas price represents the average of all system and direct (spot and firm) sales.

Undeveloped Land Holdings

November 30, 1997 (Acres)	**Gross**	**Net**
Alberta	37,027	23,542
Saskatchewan	23,724	18,861
Total	60,751	42,403

Net Asset Value

November 30	**1997**	**1996**
Reserves at PV (15%)	**$12,252,000**	$ 7,869,000
Land and seismic data	**2,440,000**	664,000
Other	**100,000**	150,000
Net debt*	**(4,288,000)**	(1,500,000)
Class B & C shares at market value**	**(2,872,000)**	(2,300,000)
Net asset value	**7,632,000**	$ 4,883,000
Class A shares outstanding (including special warrants)	**3,917,880**	2,673,580
Per Class A share - basic	**$ 1.95*** **	$ 1.83

* Long term debt plus working capital

** Closing price was $0.70 per share for Class B and $2.50 per share for Class C in 1997

*** $ 1.20 per share assuming that the Class B and Class C shares were converted at the minimum conversion value of $ 1.00

Revenue

Petroleum and natural gas sales increased 41% to a record $4,480,000 in 1997, up from $3,186,000 in 1996. Average daily petroleum production increased 50% to 477 bbls/d, while natural gas production declined to 533 mcf/d from 872 mcf/d in fiscal 1996. Production revenue increased mainly from a 31% increase in total BOE output and a 8% increase in the average net BOE price received during the year. The average net petroleum sales price was $23.51 per bbl, while the average natural gas price was $2.00 per mcf.

Granger markets the majority of its natural gas production under long term contracts with two major "netback" marketers and crude oil is sold under 30 day sale arrangements in accordance with standard industry practice.

Management believes that fixed price hedging contracts are important planning and risk management tools in moderating the variability of Granger's production revenue. During the year, net payments under such arrangements totaled approximately $127,000. At year end, the Company had 300 bopd hedged at a WTI-equivalent fixed price of Cdn. $28.69 per bbl until April 30, 1998 and an average of 200 bopd hedged at an average price of US. $20.40 for the remainder of the year.

Royalties

Third party claimants to royalties and similar production payments include the provinces of Saskatchewan and Alberta, freehold owners of mineral rights and overriding royalties to investors generally. Total royalties and production taxes paid in 1997 were $825,000 or 18.4% (16.0% net of Alberta Royalty Tax Credit) of gross production revenues, as compared to $610,000 net in 1996. The 35% increase is commensurate with the general increase in sales revenues and higher productivity of Granger's wells. These costs are expected to increase during 1998 along with growth in production volume, but decline in relation to gross revenue.

Operating Expenses

Production and operating expenses totaled $937,000 in 1997, up 12% from the previous year. Unit costs declined by 15% to $4.85 per BOE from $5.68 in 1997, largely because of lower cost new production and the sale of higher cost minor properties. These costs are expected to increase with the general increase in production but decline below $4.85 per BOE in 1998.

BOE Netbacks

	1997		1996	
	$ Per BOE	% of Total	$ Per BOE	% of Total
Production sales	23.84	100.0	22.90	100.0
(Cost of hedging)	(0.66)	(2.8)	(1.35)	(5.9)
Royalties, net of ARTC	(3.71)	(15.6)	(4.13)	(18.0)
Operating expense	(4.85)	(20.3)	(5.68)	(24.8)
Operating netback	14.62	61.3	11.74	(51.3)
General and administrative	(3.38)	(14.2)	(3.46)	(15.1)
Net interest	(0.39)	(1.6)	(0.06)	(0.3)
Cash netback	10.85	45.5	8.22	35.9
Depletion and depreciation	5.82	(24.4)	4.85	(21.2)
Deferred taxes	2.26	(9.5)	0.93	(4.0)
Net income	2.77	11.6	2.44	10.7

General and Administrative

General and administrative expense before capitalization totaled $974,000 or $5.03 per BOE. After capitalizing $320,000 (32% of the total) to recognize support costs for future exploration and development activity, the net general and administrative expense was $654,000. Overhead costs per unit of production declined 2% to $3.38 per BOE. Unit general and administrative costs are expected to decline further in 1998, mainly through production growth.

Depletion and Depreciation

Charges for depletion and depreciation were $1,125,000 or $5.82 per BOE, up from $4.85 per BOE in 1996 due to higher reserve addition costs. Total depletion and depreciation expenses are expected to increase in 1998 due to higher production volumes.

Income Taxes

Income taxes of $436,000 were deferred for 1997 and are expected to again be deferred in 1998. The ability to defer tax on a long term basis will be dependent upon the amount and type of future capital expenditures and corporate earnings.

Granger renounced a total of $1,048,070 in tax deductions to its shareholders in March 1997, effective for their 1996 tax year.

Capital Expenditures

	$000's 1997	1996
Geological and geophysical	322	206
Drilling and completion, net	3,607	2,715
Plant and facilities	1,350	708
Land and property acquisitions, net	1,054	(921)
Capitalized overhead	320	282
Other	2	48
	6,655	3,038

Liquidity and Capital Resources

At year end, the Company had bank drawings of $3,438,000 under a $3,600,000 revolving bank line of credit. A further $1,500,000 credit line, arranged to finance production purchases, was undrawn at year end.

Granger expects to utilize 100% of its cash flow from operations to finance its capital program during 1998, augmented by bank financing and additional equity issues as appropriate.

The accompanying financial statements of the Company have been prepared by management in accordance with generally accepted accounting principles and the financial and operating information presented throughout this annual report is consistent with that which is shown in the financial statements. The integrity of data in these financial statements is the responsibility of management and, to this end, management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to produce reliable accounting records.

External auditors have conducted an independent examination of corporate and accounting records in order to express their opinion of the financial statements for the years ended November 30, 1997, and 1996. The Audit Committee has reviewed these statements with management and the auditors and has reported to the Board of Directors. The Board has approved the financial statements of Granger Energy Corp. which are contained in this annual report.

Murray D. Sears
President

Neil Burrows, CMA
Manager, Accounting
and Administration

March 7, 1998

To the Shareholders

Granger Energy Corp.

We have audited the balance sheets of Granger Energy Corp. as at November 30, 1997 and 1996 and the statements of income and retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at November 30, 1997 and 1996 and the results of its operations and cash flows for the years then ended in accordance with generally accepted accounting principles.

Collins Barrow

Calgary, Alberta
January 30, 1998

Chartered Accountants

Balance Sheets

	November 30, 1997	1996
Assets		
Current assets		
Cash	**$ 57,616**	$ 50,793
Short term investments, at market value	**11,300**	–
Accounts receivable and prepaid expenses	**629,895**	626,683
	698,811	677,476
Capital assets (note 3)	**10,457,664**	5,239,231
	$11,156,475	$ 5,916,707
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**1,549,415**	1,675,192
Long-term debt (note 4)	**3,437,565**	500,000
Future site restoration provision	**175,266**	84,938
Deferred income taxes	**574,003**	138,153
Shareholders' Equity		
Share capital (note 5)	**3,340,965**	3,266,535
Special warrants (note 6)	**1,312,500**	–
Retained earnings	**766,761**	251,889
	5,420,226	3,518,424
	$11,156,475	$ 5,916,707

Approved by the Board,

Murray D. Sears
Director

Harold V. Pederson
Director

Statements of Income and Retained Earnings

	Years Ended November 30, 1997	1996
Revenue		
Petroleum and natural gas revenues	$ 4,479,846	$ 3,185,801
Royalties, net of royalty tax credits	717,440	610,217
	3,762,406	2,575,584
Expenses		
Production	937,445	839,717
General and administrative	653,997	511,535
Interest on long-term debt	75,390	8,811
Depletion and depreciation	1,125,114	717,131
	2,791,946	2,077,194
Income before taxes	970,460	498,390
Income taxes, deferred (note 7)	435,850	138,153
Net income	534,610	360,237
Retained earnings (deficit), beginning of year	251,889	(104,363)
	786,499	255,874
Shares repurchased [note 5(d)]	(19,738)	(3,985)
Retained earnings, end of year	$ 766,761	$ 251,889
Net income per share-basic [note 5(i)]	$ 0.18	$ 0.14
Net income per share-fully diluted [note 5(i)]	$ 0.15	$ 0.14

Statements of Cash Flow

	Years Ended November 30,	
	1997	1996
Operating activities		
Net income	**$ 534,610**	$ 360,237
Add item not affecting cash		
Depletion and depreciation	**1,125,114**	717,131
Deferred income taxes	**435,850**	138,153
Cash flow from operations	**2,095,574**	1,215,521
Change in non-cash working capital	**(173,583)**	596,542
	1,921,991	1,812,063
Investing activities		
Acquisition of short term investments	**(11,300)**	–
Acquisition of capital assets	**(6,899,197)**	(4,694,349)
Proceeds on disposal of capital assets	**243,807**	1,656,301
Change in non-cash working capital	**2,121**	323,344
	(6,664,569)	(2,714,704)
Financing activities		
Issuance of special warrants	**1,500,000**	–
Issuance of shares	**499,900**	1,337,000
Repurchase of shares [note 5(d)]	**(23,035)**	(4,854)
Share issuance costs	**(207,500)**	(162,209)
Proceeds (repayment) of long-term debt	**2,937,565**	(230,000)
Change in non-cash working capital	**42,471**	–
	4,749,401	939,937
Cash inflow	**6,823**	37,296
Cash, beginning of year	**50,793**	13,497
Cash, end of year	**$ 57,616**	$ 50,793

1. *Company activities*

The Company's activities are the exploration for and development of oil and gas properties in Canada.

2. *Significant accounting policies*

(a) Basis of consolidation

These financial statements include the accounts of the Company and its wholly-owned subsidiary company. On December 1, 1996 the Company and its wholly-owned subsidiary company were amalgamated.

(b) Exploration and development costs

The Company follows the full cost method of accounting whereby all costs related to the exploration for and the development of oil and gas reserves are initially capitalized. Costs capitalized include land acquisition costs, geological and geophysical expenditures, costs of drilling productive and non-productive wells, together with overhead and interest directly related to exploration and development activities and lease and well equipment. Gains or losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would significantly alter the rate of depletion and depreciation.

Costs capitalized are depleted and depreciated using the unit-of-production method based upon gross proven oil and gas reserves as determined by independent and Company engineers. For purposes of the calculation, oil and gas reserves are converted to a common unit of measure on the basis of their relative energy content.

Costs subject to depletion under the full cost method also include estimated future site restoration costs. This would include the cost of production equipment removal and environmental cleanup based upon regulations and economic circumstances at year end. The current year's provision for future site restoration is included in depletion and depreciation expenses.

In applying the full cost method, the Company performs a ceiling test which restricts the capitalized costs less accumulated depletion and depreciation from exceeding an amount equal to the estimated undiscounted value of future net revenues from proven oil and gas reserves, based on current prices and costs, and after deducting estimated future general and administrative expenses, estimated future site restoration costs, financing costs and income taxes.

The amounts recorded for depletion and depreciation of exploration and development costs, the provision for future site restoration and the ceiling test are based on estimated proven reserves, production rates, future oil and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and changes in these estimates may have a material impact on the financial statements of future periods.

(c) Joint venture accounting

Substantially all of the Company's exploration and production activities are conducted jointly with others, and accordingly these accounts reflect only the Company's proportionate interest in these activities.

(d) Depreciation

Furniture and office equipment are depreciated on the declining balance basis at rates ranging from 20% to 30% per annum.

(e) Risk management

The Company purchases forward contracts to hedge its exposure to the risks associated with fluctuating oil prices. Gains and losses associated with risk management activities are recognized as adjustments to petroleum and natural gas revenues at the time related production is sold.

(f) Flow-through shares

Share capital includes flow-through shares issued pursuant to certain provisions of the Income Tax Act (Canada). The Act provides that, where the share issuance proceeds are used for exploration and development expenditures, the related income tax deductions may be renounced to subscribers. Accordingly, these expenditures provide no income tax deduction to the Company.

Oil and gas properties and share capital are reduced by the estimated cost of the renounced tax deductions when the expenditures are incurred

3. *Capital assets*

	Cost	Accumulated Depletion and Depreciation	Net Book Value 1997	Net Book Value 1996
Petroleum & natural gas properties including exploration and development thereon	$ 9,496,421	$ 1,718,903	**$ 7,777,518**	$ 3,677,046
Lease and well equipment	3,196,335	570,229	**2,626,106**	1,489,866
Furniture and office equipment	130,048	76,008	**54,040**	72,319
	$ 12,822,804	$ 2,365,140	**$ 10,457,664**	$ 5,239,231

During the year, the Company capitalized $319,976 (1996 - $281,877) in general and administrative expenses of a total of $973,973 (1996 - $793,412).

At November 30, 1997, the Company has $2,630,891 (1996 - $2,225,794) of petroleum and natural gas costs which are not deductible for income tax purposes.

Undeveloped acreage costs not subject to depletion totals $949,903 (1996 - $230,123).

Future site restoration costs are estimated in aggregate to be $1,141,745, (1996 - $762,430) of which $99,328 (1996 - $85,964) has been charged to earnings as depletion expense in the current year. Actual abandonment costs incurred in the year amounting to $9,000 (1996 - $26,397) have been offset against the accumulated liability.

Future salvage values used in determining depletion of petroleum and natural gas properties were estimated in aggregate to be $740,042 (1996 - $759,986). The depletion expense has been reduced $91,999 (1996 - $85,808) as a result.

4. *Long-term debt*

The Company has available the following loan credit facilities with the National Bank of Canada.

	1997	1996
Revolving reducing demand loan to a maximum of $4,000,000 with availability to reduce by $100,000 beginning September 1, 1997 to March, 1998, bearing interest at prime plus 3/4% per annum.	**$ 3,437,565**	$ 500,000
Demand reducing acquisition loan, to assist in financing oil and gas property acquisitions, to a maximum $1,500,000, bearing interest at prime plus 1% per annum.	**–**	–
Treasury/swap risk line, for the purchase of various interest rate, foreign exchange and energy commodity swaps and forwards to a maximum amount of $1,000,000 and a maximum term of 48 months to be settled by the terms of the contract.	**–**	–
	$ 3,437,565	$ 500,000

The loans are secured by a general assignment of book debts and a $5,000,000 first fixed and floating charge debenture over all assets. The Company is required to meet certain financial and engineering reporting requirements. The loans are subject to review on a periodic basis at least annually; the next annual review will be undertaken before March 31, 1998. Though the loans are of the demand nature, the bank does not foresee calling the loans within the current fiscal year therefore these loans have been classified as being long-term.

5. *Share capital*

(a) Authorized

Unlimited number of Class A voting shares
Unlimited number of Class B non-voting shares
Unlimited number of Class C voting shares
Unlimited number of preferred shares

(b) Issued

	1997		1996	
	Number	**Stated Value**	Number	Stated Value
Class A Shares				
Balance, beginning of year	**2,673,580**	**$ 644,442**	2,357,300	$ 445,556
Issued for cash pursuant to Agency Agreement [note 5(h)(c)]	**255,500**	**499,900**	320,880	240,660
Repurchased under normal course issuer bid [note 5(d)]	**(11,200)**	**(3,296)**	(4,600)	(869)
Reduction in respect of income tax deductions renounced to subscribers [note 5(h)(c)]	**–**	**(191,826)**	–	–
Less: Share capital issuance costs	**–**	**(20,000)**	–	(40,905)
Balance, end of year	**2,917,880**	**929,220**	2,673,580	644,442
Class B Shares				
Balance, beginning of year	**3,712,000**	**1,921,854**	3,712,000	2,103,254
Reduction in respect of income tax deductions renounced to subscribers [note 5(e)]	**–**	**–**	–	(181,400)
Balance, end of year	**3,712,000**	**1,921,854**	3,712,000	1,921,854
Class C Shares				
Balance, beginning of year	**109,634**	**700,239**	–	(65,039)
Issued for cash pursuant to agency agreement [note 5(c)]	**–**	**–**	109,634	1,096,340
Reduction in respect of income tax deductions renounced to subscribers [note 5(c)]	**–**	**(210,348)**	–	(209,758)
Less: Share capital issuance costs	**–**	**–**	–	(121,304)
Balance, end of year	**109,634**	**489,891**	109,634	700,239
	–	**$ 3,340,965**	–	$ 3,266,535

(c) During the fiscal year 1996 pursuant to an Agency Agreement entered into between the Company and Jennings Capital Inc., the agent has sold on behalf of the Company 1,337 units at a price of $1,000 per unit. Each unit consists of 240 Class A shares with an aggregate stated value of $180 and 82 Class C shares with an aggregated stated value of $820. Five units of the offering were subscribed for by an Officer of the Company, and 20 units were subscribed for by a current Director of the Company who was not, at the time of the offering, a Director of the Company.

In accordance with the terms of the offering, and pursuant to certain provisions of the Income Tax Act, the Company intends to renounce, for income tax purposes, exploration and development expenditures incurred to holders of Class C shares. The maximum amounts to be renounced will be the total subscription price of the Class C shares $1,096,340. As at November 30, 1997, $1,096,340 in expenditures were renounced to the Class C shareholders.

The Class C shares will be convertible into Class A shares at the option of the holder, following notice from the company, at any time after December 1, 1998 and before December 1, 2000. The number of Class A shares obtained in conversion of each Class C share will be equal to $10 divided by the greater of $1 and the current market price of the Class A shares at the effective date of conversion. The Class C shares are also redeemable at the option of the Company at any time after November 1, 2000 and prior to December 1, 2000 at the fair market value of Class C shares, provided that the current market value of Class A shares exceeds $1 per share.

(d) During the year ended November 30, 1997, pursuant to a normal course issuer bid, the Company has re-acquired 11,200 (1996 - 4,600) of its Class A shares at an aggregate cost of $23,034 (1996 - $4,854). The premium paid on the repurchase over the average stated value, $19,738 (1996 - $3,985), has been charged to retained earnings. Subsequent to November 30, 1997, pursuant to a Normal Course Issuer Bid, the company has reacquired 42,200 of its Class A shares at an aggregate cost of $67,184.

(e) In accordance with the terms of the Class B shares and pursuant to certain provisions of the Income Tax Act, the Company has renounced for income tax purposes, exploration and development expenditures of $3,712,000 of which the final $1,512,000 was renounced in 1996.

The Class B shares are convertible, at the option of the holder, following notice from the company, into Class A shares at any time after February 27, 1997 and before February 27, 1999. Any Class B shares that have not been converted on or before February 27, 1999 shall be deemed to be converted on that date. The fraction of a Class A share obtained upon conversion of each Class B share will be equal to $1 divided by the greater of $1 and the weighted average trading price of the Class A shares for any consecutive 30 trading days selected by the Company commencing not more than 45 days before the conversion date.

(f) As at November 30, 1997 the Company has reserved for employees, officers and directors 362,500 Class A shares under its incentive stock option plan. These options have exercise prices ranging from $1.00 to $2.11 per share. Of the total 362,500 options, 27,500 options will expire on March 20, 1999; 190,000 options will expire September 14, 2000; 100,000 options will expire September 14, 2001 and 45,000 will expire September 14, 2002. Subsequent to year end, the Company reserved 112,500 Class A shares under its incentive Stock Option Plan. Those options have an exercise price of $1.05 and will expire on September 14, 2002. Also, subsequent to November 30, 1997, 24,000 stock options were exercised for gross proceeds of $27,150.

(g) At November 30, 1996, 234,000 Class A issued shares were held in escrow and may not be released from escrow without the written consent of the Chief of Securities Administration of the Ontario Securities Commission. As at November 30, 1997, all shares have been released from escrow.

(h) Pursuant to a Private Placement Agreement dated December 12, 1996, the Company has issued 55,500 Class A flow-through shares for aggregate proceeds of $99,900.

Pursuant to a flow-through Share Purchase Agreement dated December 24, 1996, the Company issued 200,000 Class A flow-through shares for aggregate proceeds of $400, 000.

In accordance with the terms of the agreements and pursuant to certain provisions of the Income Tax Act, the corporation renounced for income tax purposes, $499,900 exploration and development expenditures to the holders of these shares.

(i) Net income per share

Net income per share is calculated based on the weighted average number of Class A common shares outstanding during the year of 2,913,396 (November 30, 1996 - 2,655,156). The conversion of Class B and Class C shares is related to the market value of the Class A common shares. Class B and Class C shareholders do not participate in the earnings of the Company until conversion and the Class B and Class C shares have not been considered in the calculation of fully diluted net income per share.

(j) Public offering

Subsequent to year end, pursuant to a Prospectus dated December 8, 1997, the Company completed an offering in which it sold, on a best efforts basis, 567,186 units of flow through Class A shares at $1.85 per share and 1,054,797 units of Class A shares at $1.65 per share, for gross proceeds of $2,789,709 before agents commissions of $209,228 and estimated expenses of the offering of $50,000. Each flow through share will entitle the holder to be renounced qualifying expenditures in the amount of $1.85 per flow through share.

6. *Special warrants*

Pursuant to an Agency Agreement dated July 8, 1997, the Company has completed an offering in which it sold 1,000,000 units at a price of $1.50 per unit. Each unit consists of one flow-through Special Warrant and one Regular Special Warrant. Each flow-through Special Warrant will be exercisable for one-half Class A share. Each Regular Special Warrant will be exercisable for 1/2 Class A share and 1/2 of a warrant at no additional cost. Each whole warrant will be exercisable for one Class A share at an exercise price of $2.00 per Class A share prior to February 8, 1998. The flow-through Special Warrants and Regular Special Warrants will be exercisable on receipt for the Prospectus being obtained from the Securities Commissions. Pursuant to a Prospectus dated and cleared December 8, 1997, 1,000,000 Class A shares and 500,000 purchase warrants were qualified for distribution upon exercise of previously issued flow through and special warrants. All flow through and special warrants have been exercised.

7. *Income taxes*

Income tax expense differs from that which would be expected from applying the effective Canadian federal and provincial income tax rates to income before income taxes. Details of the changes are set out as follows:

	1997	1996
Effective Canadian income tax rate	**44.62%**	44.62%
Computed "expected" income taxes	**$ 433,020**	$ 222,382
Increase (decrease) in income taxes resulting from:		
Non-deductible crown payment, net of Alberta royalty tax credit	**176,849**	108,835
Resource allowance	**(242,374)**	(204,162)
Share capital issuance costs	**(77,402)**	(58,885)
Depletion and depreciation on non-tax based assets	**118,554**	124,795
Deferred tax debit not recognized	**-**	(57,429)
Other	**27,203**	2,617
Income taxes, deferred	**$ 435,850**	$ 138,153

8. *Financial instruments*

(a) Risk management

In order to manage exposure to fluctuations in oil prices, the Company entered into forward contracts fixing the price of oil for 90,000 barrels (1996 - 46,000 barrels). Petroleum and natural gas revenues include losses related to these contracts amounting to $127,406 (1996 - $200,386).

The Company has entered into the following forward contracts, the full benefits (costs) of which have yet to be realized:

	Volumes (Barrels per Month)	Prices	
March 1, 1997 to December 31, 1997	3,000	CDN$	27.50
November 1, 1997 to April 30, 1998	3,000	CDN $	27.95
January 1, 1998 to December 31, 1998	3,000	US $	20.10
January 1, 1998 to December 31, 1998	3,000	US $	20.70

(b) Fair values

The fair values of all recognized financial instruments approximate their carrying amount.

The fair value of contracts entered into as part of the Company's risk management activities is equal to the unrealized gains (losses) inherent in the contracts. Based on mark to market valuations as at November 30, 1997, the fair value of these contracts is $87,128 (1996 - $236,776).

(c) Interest rate risk

The Company is exposed to interest rate cashflow risk to the extent that the carrying value of its long-term debt is at a floating rate of interest.

(d) Credit risk

The Company's maximum credit risk exposure is limited to the carrying value of its accounts receivable and any inherent gains related to its risk management activities. At November 30, 1997, the maximum credit risk was $717,023 (1996 - $863,459).

9. *Related party transaction*

During fiscal 1996, the Company sold certain oil and gas properties to a related party for proceeds of $970,000. A director of the Company is a director and officer of the company who purchased the properties. The transaction was recorded at the exchange amount which approximates the fair market value of the properties.

10. *Commitments*

The Company has entered a sublease agreement for renting its office premises. The agreement expires September 29, 1999 and calls for minimum monthly payments for rent and operating costs of $3,894. The amounts due are subject to adjustments based on actual operating costs

Board of Directors

I. Lorne Levorson
Levorson Resources Management Ltd.
Calgary, Alberta

Harold V. Pedersen
President, Jordan Petroleum Ltd.
Calgary, Alberta

Richard A. Schultz
Vice President, Production and Operations,
Granger Energy Corp.
Calgary, Alberta

Murray D. Sears
President, Granger Energy Corp.
Calgary, Alberta

Auditors

Collins Barrow
Calgary, Alberta

Banker

National Bank of Canada
Calgary, Alberta

Solicitors

Burstall Ward
Calgary, Alberta

Registrar and Transfer Agents

The R-M Trust Company
Calgary and Toronto

Officers & Management

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Richard A. Schultz
Vice President,
Production and Operations

Bradley D. Maynes
Vice President, Exploration

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Land Manager

Neil G. Burrows
Manager, Accounting,
and Administration

Harley L. Winger
Secretary
Partner, Burstall Ward

Mary C. Blue
Assistant Secretary,
Senior Vice President,
Jordan Petroleum Ltd.

Exchange Listings

The Alberta Stock Exchange
Stock Symbols: GAS.A, GAS.B, GAS.C

Evaluation engineers

Paddock Lindstrom & Associates

Head Office

1770, 202. 6th Avenue S.W.
Calgary, Alberta T2P 2R9

Tel: (403) 237.0083
Fax: (403) 237.0085
Internet: www.grangerenergy.com
E-Mail: grangere@cadvision.com

Produced by Canada Corporate Communications Inc.

Granger
ENERGY CORP.

1770, 202. 6th Avenue S.W.
Calgary, Alberta T2P 2R9